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September 21, 2005

Mr. David H. Meyer
Acting Deputy Director
Office of Electricity Delivery and Energy Reliability, TD-1
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Re: Energy Policy Act of 2005, Section 1234 Economic Dispatch Study

Dear Mr. Meyer:

Set forth below are LG&E Energy's responses to the six "Questions for Stakeholders" developed by the Department of Energy as part of the Department's efforts under Section 1234 of the Energy Policy Act of 2005 to survey and study current economic dispatch practices. LG&E Energy certainly appreciates the opportunity to participate in this important Department of Energy study.

1) What are the procedures now used in your region for economic dispatch? Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

LG&E Energy Corporation L.L.C. is the holding company for two utility operating companies, Louisville Gas & Electric (LG&E) and Kentucky Utilities (KU). LG&E and KU-owned resources are today dispatched by the Midwest ISO("MISO") subject to that RTO's Day Ahead and Real Time energy markets.

The Midwest ISO extends across 15 states and the province of Manitoba. MISO coordinates reliability across approximately 97,000 miles of transmission lines. The Midwest ISO experienced a regional coincident peak load of 119,000 MW and has present within its geographic footprint approximately 131,000 MW of utility and non-utility-owned generation.

In addition, Western Kentucky Energy ("WKE") is a subsidiary of LG&E Energy and is a non-utility generator. WKE generates electricity at four stations that it operates and maintains under a 25-year lease agreement with Big Rivers Electric Corporation. The stations are owned by Big Rivers Electric Corporation with the exception of HMP&L Station Two which is owned by Henderson Municipal Power and Light. Economic dispatch of the WKE-operated generation is

conducted by LG&E Energy Marketing ("LEM") in order to meet contracted load and optimize off system sales and purchasing.

2) Is the Act's definition of economic dispatch (see above) appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

The Act's definition of "economic dispatch" lacks any temporal component. It is erroneous to view economic dispatch as a real-time or single day event. Dispatch should proceed so as to insure economic optimization over the course of at least a season and perhaps more appropriately a calendar year.

The geographic area over which economic dispatch should take place ought to be defined by the relevant stakeholders including the participating companies and state regulatory commissions. A voluntary participation insures that those who do elect to participate foresee value in that participation.

The factors and considerations that one should bear in mind when evaluating economic dispatch do tend to fall into either the cost or reliability category. However when speaking of reliability it is not only the real-time reliability at issue; there is also the reliability of the bulk power system next month or six months from now. Thus one should economically optimize costs over a reasonable period of time to account for, for example, expected plant availability and environmental limitations.

It should also be noted that cost in the case of dispatching a vertically integrated utility generation portfolio refers to the actual production costs of the generator being dispatched, and it is the weighted average cost of dispatched generation that utilities ultimately charge customers. In the case of an RTO centrally-administered market, like MISO, cost is based on generator offers which need not to be the actual production cost of the generator. Moreover, the "cost" to consumers in an RTO-administered market is not calculated based on weighted average of actual production costs, but rather the market clearing price established by the offer of the last generator dispatched. With the DOE definition of economic dispatch in mind LG&E maintains that its historic dispatch in combination with traditional cost-based ratemaking provided energy at lowest cost to consumers.

Because RTO-administered market dispatch does not provide energy at lowest cost to customers relative to the traditional system dispatch utilized in the past by LG&E, LG&E questions whether the RTO market-based dispatch in which LG&E currently participates can also qualify as economic dispatch under the DOE definition. In order to believe RTO-market dispatch also meets the DOE definition one would have to accept the existence and equivalence of two distinct paradigms and ignore the cost and pricing distinctions that exist between the two.

3) How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please indicate what the difference is, how often this occurs, and its impacts upon non-utility generation and upon retail electricity users. If you have specific analyses or studies that document your position, please provide them.

Economic dispatch procedures do not differ by class of generation, but rather by the rules governing, for example, the Midwest ISO markets and the dispatch methodology employed by a more traditional, vertically integrated system. With Day-Ahead and Real-Time energy imbalance markets using locational market pricing ("LMP"), asset owners offer generation to the MISO at market-based prices. Energy from utility-owned generation and non-utility generation alike are theoretically dispatched using an objective function that minimizes payments to dispatched generators, subject to reliability constraints. Payments made to generators with revenues collected from customers are based on the highest priced accepted energy bid and any other required payments to generators not recovered in the energy markets are also assigned as costs to customers.

In the more traditional utility dispatch methodology, state regulatory commissions determine how utilities should meet their resource needs. Resources that are approved as a part of the utility's resource mix are economically dispatched based on actual production costs along with any available non-utility generation that the system dispatcher knows is more cost effective than self-generated energy.

Actual operational practices within MISO do in fact differ from the formal tariff procedures. The Companies' primary operational concern is that MISO's LMP-based security-constrained economic dispatch ("SCED") appears not to be driving generator dispatch at all times. Two particular issues lead to this conclusion. First, MISO has on numerous occasions resorted to "manual" redispatch of the Companies' units (i.e. the MISO reliability coordinator verbally directs the Companies to redispatch their units, even though LMP does not support such redispatch and the MISO reliability coordinator has not declared an appropriate Transmission Load Reduction ("TLR") level. This phenomenon is particularly puzzling in light of the fact that the premise behind the Day 2 market was to reduce the need for TLR-based redispatch through LMP's that were designed to manage congestion more efficiently and transparently. Presumably, if LMP's were working properly, there should be few occasions necessitating TLR's and manual redispatch should never occur.

Also, for reason explained in response to Question 5 below, the MISO dispatch often requires MISO to commit the Companies' combustion turbines at times when market prices suggest those units should not run. From April 1, 2005 through June 30, 2005, MISO dispatched the Companies' CT's 2,861 hours, of which only 215 hours were dispatched at times when the

LMP's were clearly indicating it was economic to do; a mere 7.5% of the total Companies' CT runtime.

4) What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by non-utility generators, please explain the changes you recommend.

The definition of economic dispatch as defined by Section 1234 of the Energy Policy Act is pivotal to providing the correct policy direction on this question. In particular consider the emphasis on "lowest cost" while seeking to achieve acceptable reliability given system conditions. This questions seems to equate increased dispatch of non-utility generation with the goal of "lowest cost" economic dispatch, which is not a good assumption.

Whether or not non-utility generation is the lowest cost incremental resource at a given time clearly depends on the operational and financial characteristics of available alternative generation sources. Thus the promotion of non-utility generation dispatch as an end to itself would, LG&E maintains, often prove counterproductive to the defined goal of economic dispatch.

5) If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide? If you have specific analyses to support your position, please provide them to us.

The dispatch methodology employed by the Midwest ISO more easily facilitates inclusion of non-utility owned generation in the regional dispatch. However, the MISO dispatch also results in much less efficient commitment of capacity than had been the case prior to implementation of Day 2. This is because the MISO dispatchers do not participate in the market, that is to say they are not out in the marketplace soliciting or making offers to other market participants. As a result, when MISO experiences changes in supply, be it imports or forced outages, MISO is far more inclined to quickly commit additional capacity in order to insure that load can be met. This capacity, being selected based solely on startup and no load basis, is, when the energy cost is factored in, more often than not out of economic merit order. This observed tendency to over commit capacity adds costs to retail customers.

A more general observation over the MISO methodology of dispatch is that it incentivizes generators to seek the highest offer price that the market can bear. This incentive along with use of a market-clearing price as opposed to pay as you bid greatly increases costs to customers. Contrasted with the dispatch previously employed by LG&E in which economic merit order was based on actual production or procurement costs, which are then recovered from customers on a

weighted average basis, and one cannot help but see why regionally-administered, market-based dispatch performed by a non-market participant dispatcher who is immune from cost consequences produces higher costs to consumers.

6) Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?

Reliability focuses on security in the short term and adequacy over the long term.

Reliability in the short-term constrains the extent to which one can follow a purely economic dispatch. In the longer term, economic dispatch must be performed with an eye toward future resource adequacy; one cannot simply today dispatch on a purely economic basis that ignores the ongoing responsibility to insure sufficient generation be available for tomorrow and beyond.

Moreover, any system of dispatch that furthers the organizational distance between dispatcher, transmission system operator and plant operator will introduce additional communications challenges. As a result, striving to include independently operated generation in the dispatch, as an end in itself or establish an independent dispatcher organizationally separate from all plant owners, necessarily gives rise to additional reliability challenges.

All dispatching methodologies attempt to optimize economically within the established paradigms discussed in response to Question 2 above, however important differences arise due to different levels of information available to the dispatcher. Traditional economic dispatch results in the dispatcher having more information available to him due to his knowledge of internal costs and active participation in the market. Bidding incentives and pricing aside, RTO-administered, market-based dispatch suffers from the establishment of more islands of information which adds inefficiency and ultimately cost to consumers, and complicates reliable operation of the bulk power system. These costs and complications must be weighed when evaluating the desirability of achieving ever more efficient economic dispatch or policies to promote development and use of non-utility-owned generation.

LG&E believe that while a centrally administered dispatch may make it easier for an independently-owned generator to participate in the dispatch, it also results in increased costs and reliability concerns due to more complicated communications requirements. LG&E believe that, after factoring in capacity procurement and commitment along with energy dispatch, the centrally-administered, market-based dispatch currently conducted by the Midwest ISO neither conforms with the DOE definition of “economic dispatch,” nor does it in any way serve to provide energy at the lowest cost to the extent LG&E/KU’s system dispatch did prior to April 1, 2005.

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Again, LG&E Energy appreciates this opportunity to provide comments on these important matters. If you have any questions concerning LG&E's comments please do not hesitate to contact me at (502)627-3414.

Respectfully submitted,

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